

# **TRANSMISSION GRID ACCESS AND PRICING IN NORWAY, SPAIN AND CALIFORNIA – A COMPARATIVE STUDY**

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## **1. Introduction**

The openness of the transmission grid and the incentives given by transmission pricing form the foundation for retail and wholesale competition in the electricity market. The deregulated markets of Norway, Spain, and California all have introduced retail access and wholesale competition, although with different approaches to pricing of transmission grid services. This paper will briefly describe the three different solutions, and discuss some of their implications.

Of the three electricity systems, Norway was the first to open the grid to competition in electricity trade. The Norwegian Energy Law of 1990 introduced open competition to wholesale and retail trade starting January 1991. In Spain, the Electricity Law of 1997 came into force early in 1998. Wholesale and retail markets in California were opened for competition on April 1, 1998, following the passage of Assembly Bill 1890, in August 1996. Introducing competition in electricity markets also implies introducing Third Party Access to the transmission grid. All potential competitors have to be given access to the grid in order to compete, no matter who owns the actual wires. This principle raises several challenges, notably, how to price transmission services. Who is to pay for which transmission services?

Table 1 sums up the definition of transmission and distribution in the three systems.

**Table 1:** Grid included in different grid levels.

GRID LEVEL	NORWAY	SPAIN	CALIFORNIA
Transmission Grid	420 kV, 300 kV, and parts of the 132 kV grid providing transmission function	400kV, 220 kV, and parts of lower voltage levels providing transmission function	Transmission grid includes all inter-state connections and any parts of low voltage with a transmission function
Regional Grid	60-132 kV	HV (36kV<V<220 kV) MV (0.38kV<V<36 kV) LV (0.38 and 0.22 kV)	Distribution grid includes all intra-state connections
Distribution Grid	≤ 22 kV		

The Norwegian grid is divided into three levels depending on its function. The transmission grid includes all parts of the national grid having a transmission function, meaning that some lower voltage levels also are included. In Spain, the definition of the transmission grid is similar, including the 400 kV and 220 kV national grid as well as lower voltage installations that could affect transmission operation or generation dispatch. For historic reasons, wholesale electricity transactions in the US are regulated by the federal government through the FERC. However, operations of utility systems within one state fall primarily under state jurisdiction. Because the utility systems in California generally are large and exchanges between them limited, the role of FERC was small prior to restructuring, although the state is a large importer of power.

## 2. Institutional Settings

When deregulation was implemented in Norway, the transmission functions of the state-owned utility Statkraft was established as a separate company. The new company, Statnett SF, has since operated the Norwegian transmission grid and is responsible for international connections. Statnett owns approximately 76 percent of the transmission grid that it operates, with regional grid owners owning the remainder. Through the “Central Grid Agreement,” Statnett rents parts of the transmission grid owned by the regional grid owners. Furthermore, Statnett is the Norwegian System Operator, being responsible for system dispatch, ancillary service procurement, etc. The Norwegian Water Resources and Energy Directorate (NVE) regulates Statnett, both its function as the Transmission Grid Company and as System Operator.

Since 1984, an independent company, Red Eléctrica de España (REE), has operated the Spanish transmission system. REE owns 95 percent of the 400 kV grid and 30 percent of the 220 kV grid. As the principal Spanish transmission owner and System Operator, REE controls transmission operations, technical dispatch to avoid congestion or other operational problems, international

exchanges, as well as manages ancillary services. REE is 60% state-owned, but the Government plans to divest 30% of its shareholdings in the near future.

When California's electricity supply was deregulated, an Independent System Operator (California ISO) was established from scratch. The California ISO is responsible for system dispatch, ancillary services etc., and is a registered non-profit corporation. The California ISO does not own any transmission facilities. However, the California ISO controls the transmission grid of the Transmission Owners. Being concerned only with wholesale transactions, California ISO would not have been subject to state of California regulation but would have fallen directly under federal oversight by FERC. To avoid this loss of jurisdiction, AB 1890 established the Electricity Oversight Board specifically to regulate the new industry institutions.

### **3. Expectations to the Transmission Tariffs**

The transmission tariffs are generally required to fulfil several purposes. First of all, transmission tariffs are required to promote **efficiency**, meaning that users of the transmission grid should be given signals to behave in a societally efficient manner. This is normally done through some kind of marginal pricing. The Marginal Loss Factors of Norway, Loss Penalty Factors of Spain, and the Generation Meter Multipliers of California, are all elements reflecting the marginal costs of operating the transmission grid. However, due to the capital-intensive character of grid, marginal pricing of transmission services does not provide sufficient cost recovery for the grid owners. For instance, the Norwegian Marginal Loss Factors only cover approximately 15% of the costs of operating the transmission grid. The remaining 85% are related to fixed costs. Therefore, in addition to providing incentives to use the transmission system efficiently, the transmission tariffs are required to provide **cost recovery** for the grid owners. Distributing the costs not covered through marginal pricing is a **cost allocation** problem that requires some kind of allocational goals. This could, for instance, be to promote specific locations of load and generation as well as specific time-of-use behavior.

### **4. Principles, Structures and Elements of the National Transmission Tariffs**

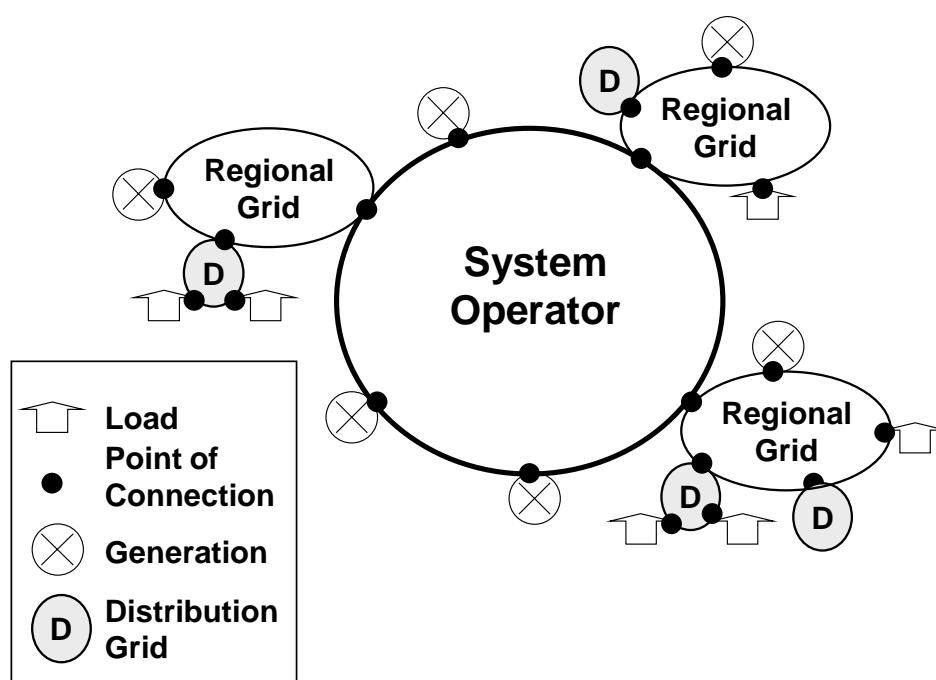
Table 2 gives a brief overview of the transmission tariff elements in the three electrical systems being compared, and what costs the different elements reflect.

**Table 2:** Elements of the transmission tariffs of Norway, Spain and California.

Costs	Norway	Spain	California
<b>Transmission Losses</b>	Marginal Loss Factors (generation and load)	Loss Penalty Factors (generation and load in the energy market)	Generation Meter Multipliers and Tie-line Meter Multipliers
<b>Congestion Management</b>	Zonal Pricing through Capacity Charge	Network constraint management procedure	Zonal Pricing through Usage Charge and Grid Operations Charge
<b>Fixed Costs</b>	Demand Charge, Connection Charge	Access Charge (energy and demand components)	Access Charge
<b>Investments</b>	Construction Contribution/General Tariff elements	Centralized planning by the System Operator	Construction Contribution

## Norway

Norway implemented Point of Connection Tariffs in 1991 during deregulation. The basic principle of the Point of Connection Tariff is that each grid user (end-users, generators, or other grid owners) pays a transmission tariff depending on the point of connection. The transmission tariff at each point of connection is calculated relative to a defined, fictitious “market place” in the central grid. The seller pays for the electricity being transported into the market place, while the customer pays for transportation out of the market place. The structure of the Norwegian Point of Connection Tariffs is illustrated by Figure 1.



**Figure 1.** The Point of Connection Tariffs.

The guidelines for calculating transmission tariffs require the tariffs for withdrawal and injection to be structured as follows:

1. Volume dependent tariff elements vary according to grid user's withdrawal or injection.
2. Other Tariff elements do not vary according to the grid user's metered withdrawal or injection, and should recover the costs not covered through the volume dependent tariff elements. The charge is intended to be neutral with respect to consumption.

#### *Transmission Losses and Congestion Costs through Volume Dependent Tariff Elements*

Grid owners are responsible for grid losses in Norway. These losses are bought in the market, and therefore reflect the current spot price. Marginal costs of electricity transmission must be reflected in the volume dependent part of the tariff. This normally implies that grid losses, reflecting varying physical losses, as well as spot prices, are covered through a volume dependent charge.

In the transmission tariff, the volume dependent charge, i.e., the **Energy Charge**, must be geographically and periodically differentiated. Statnett calculates the **Marginal Loss Percentages** through representative load flow simulations for the Norwegian/Swedish system. Each tie point (with a total of 141 points) in the Norwegian transmission grid has an individual Marginal Loss Percentage attached to it, and the absolute value for injection versus withdrawal is the same at each tie point (however, with different denominations). The denominations will vary for load vs. generation depending on the balance between the two at the specific tie point. The charges are calculated for periods of 8 – 10 weeks, a fortnight in advance at the latest. The charge is differentiated seasonally, as well as for day and night.

Whenever there is congestion between two zones, the volume dependent charge will additionally include the **Capacity Charge**, which reflects the zonal price differences. The generators in surplus zones (generation>demand) face a positive Capacity Charge. The charge is the difference between the zonal price (as calculated by Nord Pool) and the system price (unrestricted Elspot price). The generators in deficit zones (generation<demand) will, on the other hand, face a Capacity Charge with negative denomination made up from the difference between the zonal price and the system price. This way of relieving congestion is similar to the Inter-Zonal congestion management described for California.

### *Fixed Costs through Other Charges*

The transmission tariff consists of two other charges, i.e., the **Connection Charge** and the **Demand Charge**. The other charges are differentiated with regard to injection and withdrawal, and the hour with maximum load in the areas “North,” “Middle,” and “South,” respectively, is used for settlement.

The Connection Charge is a gross element meaning that the total available demand in winter at each tie point is used as the basis for calculation. End users face a Connection Charge based on total withdrawal from the grid, while the suppliers face a Connection Charge based on total injection to the grid.

The Demand Charge (as opposed to the Connection Charge) is a net element of the transmission tariff, meaning that the grid user’s net exchange with the transmission grid is used as the basis for settlement. The end user is charged for net withdrawal from, while the supplier is charged for net injections to, the grid.

The difference between the Connection Charge and the Demand Charge is the volume used for settlement. While the Connection Charge is based on total withdrawal and/or injection from/to the grid, the Demand Charge is based on either net withdrawal or net injection.

### *Future Investments*

Statnett is responsible for grid expansion, new investment, and maintenance of the transmission grid. Future investment in the grid can be financed in two ways: [1] through the general tariff elements described above or [2] through a **Construction Contribution**. The Construction Contribution is a payment charged to grid users benefiting from the grid investment in question, and is a payment made only once. In other words, in addition to paying the Construction Contribution, contributors pay the general tariff as do all other grid users. The Construction Contribution may be positive or negative, depending on what Statnett wants to promote and how the possible investment influences on the power flow and costs.

### *Norwegian “Peculiarities”*

As of January 1, 1997, Compensation for Energy not Supplied (ENS) was introduced for grid users connected to the central transmission grid. The introduction of this compensation was a response to the introduction of a new regulatory regime based on revenue caps. Through this

element, grid users get compensated when major outages in the transmission grid occur. The idea is that tie points of a socially efficient grid will have different reliability, and that the system under certain situations can be run with lower operational security than estimated by n-1 criteria. ENS is therefore expected to contribute to investment decisions being more efficient than previously, and hence reduce overall transmission rates.

## **Spain**

The transmission grid charges are embodied in the regulated **Full-Service Tariffs** (i.e., tariffs for regulated customers) and in the **Access Tariffs** (for qualified customers who have exerted their rights). The term “grid charges” may cause confusion, as there are no transmission tolls separate from distribution tolls in Spain. Qualified customers must pay Access Tariffs for the use of transmission and distribution lines. The “recognized transmission revenues” are collected through Full-service and Access Tariffs from distributors by the regulator CNSE, who then allocates the money among Red Eléctrica and other transmission owners, according to pre-defined revenue entitlements.

These regulated Full-Service Tariffs and Access Tariffs are to cover transmission and distribution costs as well as other institutional and specific regulated costs. Voltage levels in 6 categories differentiate the tariffs: [1] Lower voltage, [2] 1 to 14 kV, [3] 14 to 36 kV, [4] 36 to 72.5 kV, [5] 72.5 to 145 kV, [6] more than 145 kV. The tariffs furthermore have two separate components: (1) a capacity term as a function of the requested **demand** (kW) and (2) an energy term as a function of the requested **energy** (kWh). In medium voltage and higher voltage grid, Access Tariffs are time-differentiated with regard to daily and seasonal variations.

### *Transmission Losses through Loss Penalty Factors*

Every market agent connected to the Spanish transmission grid (supplier or end-user) has an associated transmission loss participation factor (Loss Penalty Factor) depending on its marginal contribution to the losses calculated in the specific point of connection. Transmission losses are taken into account directly in the daily energy market and they are not considered as an explicit grid charge. Generation and demand are matched in the central market model with a single pool price, where transmission losses are taken into account (see OM 1998). Generators in exporting areas will be remunerated for less energy than generated, while consumers in importing areas will pay for more energy than consumed. Initially, in the regulatory transition period, all locational



signals from existing generators and regulated loads will be ignored, and transmission loss costs are charged to the end-users.

### *Congestion Costs through Uplift*

A grid constraint management procedure is applied by the System Operator during the sequence of the day-ahead energy market operations as well as in real time. The System Operator, taking into account the quantities (generation and load) that have been scheduled for every hour in the day-ahead energy market operations, performs a grid analysis to evaluate possible congestion or voltage problems. If there is any congestion, the System Operator will modify the results of the daily market operations, and minimize the cost of the deviations:

- Forced-in generation (from *constrained-on units*) will be paid the *offer price* that they submitted in the day ahead market for the electricity generated in those scheduling periods in which those units are called to solve transmission constraints.
- Displaced units will not receive any compensation payment for their constrained off generation.
- Ad hoc procedures may be defined for permanent constraints.

If constraints appear in real time, the System Operator can resort to emergency procedures. The extra-cost incurred in removing all grid constraints will be added to the costs related to ancillary services. These costs will be recovered through an uplift to the energy price and charged to the total demand in each hour.

### *Future Investments*

All grid users can promote construction and planning of new transmission facilities, but the System Operator must coordinate different proposals. All new proposed facilities must be considered in the process of evaluating development plans for the grid. Construction, operation, and maintenance of the new facilities will be established by competitive bidding mechanisms. The authorized new investment is considered to result in new allowed revenues for the transmission owner.

### *Spanish “Peculiarities”*

Transmission owners currently have an economic incentive to increase the availability of transmission facilities above a level set as a reference. However, if actual availability is lower than the reference level, the transmission owners are economically penalized.

### **California**

The California ISO charges for transmission services on behalf of the Transmission Owners.

#### *Transmission Losses through Generation Meter Multipliers and Tie-line Meter Multipliers*

For each tie-point in the transmission grid the California ISO calculates Generation Meter Multipliers (GMMs) and Tie-line Meter Multipliers (TMMs). When generators submit schedules at the injection nodes, the grid losses have to be included in the schedule through multiplying the committed quantity with a factor including the grid losses – the GMMs. Likewise, market participants submitting schedules at the specific tie-lines have to multiply the committed quantity with the TMMs. Scheduling Coordinators are charged for the TMMs. The California ISO calculates these GMMs and TMMs through load flow analysis. The GMMs and TMMs vary between locations and over time, and the California ISO calculates these factors daily.

#### *Congestion Costs through Usage Charges and Grid Operation Charges*

Scheduling Coordinators are charged by the California ISO for the use of congested inter-zonal interfaces. In California 26 major transmission corridors or paths have been defined, which link the different electrical zones. If the load flow on a path resulting from the proposed schedules exceeds the maximum allowed flow limit, then the path is congested. The main use of the zones is to determine the transmission **Usage Charge** across zones and to establish locational differentiation of the Power Exchange market-clearing price when inter-zonal congestion exists.

The Usage Charge is calculated by the California ISO as the hourly marginal value of an incremental kW of inter-zonal capacity. This Usage Charge multiplied by the scheduled flow must be paid by each Scheduling Coordinator who uses the interface in the congested direction, and it will be used to compensate Scheduling Coordinators who, in effect, create transmission capacity through schedules in the opposite direction of congestion. The Day-Ahead Usage Charges are applied to schedules accepted in the Day-Ahead market. The Hour-Ahead Usage Charges are applied to schedules submitted and accepted after the Day-Ahead scheduling and the Day-Ahead congestion management procedures have concluded.

In case of congestion, voltage degradation, or other operational problems inside an electrical zone, the California ISO will re-dispatch generation units to meet reliability requirements inside that zone. The California ISO will minimize the cost of this re-dispatch based on the “adjustment bids” that Scheduling Coordinators have provided. This extra-cost will be recovered through the **Grid Operations Charge** which must be paid to the California ISO by all Scheduling Coordinators in proportion to their demand within and exports from the considered zone.

#### *Fixed Costs through Access Charges*

**Access Charges** are determined for each participating transmission owner to recover the full revenue requirement (i.e., the full grid costs, primarily sunk investment costs) associated with its transmission facilities transferred to the California ISO’s operational control. The transmission owners are primarily the three Investor Owned Utilities, though some publicly-owned utilities might also decide to join. All market participants withdrawing energy from the California ISO controlled grid must pay an Access Charge. The revenue requirements are adjusted taking into account the revenues coming from “Wheeling Access Charges” and “Usage Charges” known as “Transmission Revenue Credits.”

Access charges are calculated and/or paid depending on the following situations (ISO Tariff, 1998):

1. Local publicly owned electric utilities, whose transmission facilities are under California ISO operational control, must file their proposed access charges with the California ISO. The California ISO requests that the appropriate Local Regulatory Authority review the Access Charge.
2. Any self-sufficient participating transmission owner shall bear no responsibility for the Access Charge of any other participating transmission owners.
3. Any dependent participating transmission owner must pay an access charge to the participating transmission owner to which it is physically connected.
4. Any Scheduling Coordinator scheduling a wheeling transaction must pay the California ISO the product of [1] the applicable Wheeling Access Charge, and [2] the schedules of wheeling in kWh at each scheduling point associated with that transaction. The scheduling points where the charge is applicable are the points in the California ISO grid where energy is scheduled to exit the grid. The Wheeling Access Charge is determined for each participating transmission owner taking into account its transmission revenue requirement and its annual energy deliveries.

5. Any end-user must pay an Access Charge for unbundled retail transmission service. These charges are designed as a single, rolled-in rate that is uniform for similar customers in each utility's service area, estimated to be approximately \$16/kWyr for SCE, \$17/kWyr for PG&E, and \$36/kWyr for SDG&E.

A major attraction of this form of cost allocation is the minimization of cost shifting both across utilities and between customers of each existing utility. Those utilities that are found to be “dependent” upon the transmission assets of another utility are responsible for paying some of the revenue-requirement of that utility's transmission assets. This helps overcome the free-rider concern (i.e., the concern that charges place an unfair burden on those utilities and customers that do not heavily rely on the transmission system).

#### *Future Investments*

In California, transmission owners included in the California ISO control area, the California ISO, or any other market participant can propose transmission projects. Participating transmission owners are required to develop annual plans for their transmission grid, and potential projects must be coordinated with the Western System Coordinating Council and the Regional Transmission Groups (RTGs).

Currently, the assessment of project need and cost responsibility is determined in two different ways depending on whether the project is expected to a) promote economic efficiency, or b) improve system reliability. For projects promoting economic efficiency the sponsor has to demonstrate that the economic benefits exceed the project costs. The sponsor furthermore has to propose a pricing methodology that assigns the costs to the beneficiaries in proportion to their net benefits. For reliability driven projects, the California ISO can propose any upgrades to ensure system reliability, and the participating transmission owners shall be obligated to construct them. Lower cost alternatives to construction of transmission additions, such as expansion of existing facilities, demand side management, or reactive support, must be considered. Note, however, that recovery of investment expenditures falls under the jurisdiction of FERC.

#### *California “Peculiarities”*

Markets for Firm Transmission Rights (FTR) are scheduled implemented over the course of 1999. These rights are expected to negotiate the ownership of the congested paths, and to provide market mechanisms to improve economic efficiency in the use of the transmission grid. The net

Usage Charge revenues for each inter-zonal interface shall be paid to FTR holders according to the number of FTRs they own related to the interface in question. To the extent this amount is not paid to the FTR holders, the net Usage Charge revenues are to be paid to the participating transmission owner who owns the interface.

## 5. Discussion and Conclusions: Incentives Given on Short and Long Term

Table 3 sums up incentives given by the transmission tariffs described above. The incentives considered are signals given with regard to [1] location of load or generation, and [2] timing of withdrawal or injection to the transmission grid.

**Table 3:** Incentives given by the different elements of the transmission tariffs.

Charges for:	Norway		Spain		California	
	Load	Generation	Load	Generation	Load	Generation
Transmission Losses	Both	Both	Both	Both	Both (TMMs)	Both (GMMs/TMMs)
Congestion Management	Both	Both	No	Both	Both	Both
Fixed Costs	Neutral	Neutral	Timing	No Charge	Timing	Timing
Future Investments	Location	Location	No	No	Location	Location

All three electrical systems have implemented elements of marginal pricing in the transmission tariffs. Transmission losses as well as congestion costs reflect the marginal costs of the systems. These elements of the transmission tariffs therefore provide short-term signals to the grid users with regard to time of use and location of generation and load.

Fixed costs are covered by an energy component in California, while Norway and Spain have implemented both an energy component and a demand component to recover fixed costs. None of the systems described provide strong incentives in the “fixed cost element” of the transmission tariffs.

To some extent the California Access Charge is time differentiated, and each area of the three large Investor Owned Utilities has somewhat different Access Charges. However, the signals provided by this charge are limited. In Norway, the tariff elements to cover for fixed costs are supposed to be neutral. However, experience shows that the market participants – both load and

generation - try to forecast the peak load in order to avoid the high demand charge settled based on the annual peak. Consequently, this charge has some incentives for time of use in it. In Spain fixed costs are recovered through both an energy element and a demand element. Only load faces these elements, however. This charge provides signals for time of use for loads.

One-time payments and different country specific elements provide possible long-term signals in the described systems. Norway has opened for construction contributions to recover future investments, and Statnett negotiates with the affected users prior to making such investments. The former regulatory regime – rate of return regulation - promoted excess grid investments. The new regulatory regime, however, promotes costs savings through revenue caps, efficiency factors and earnings sharing mechanisms. To avoid the grid quality to deteriorate below what is societal beneficial, a compensation for energy not delivered is implemented. These elements together provide the long-term signals of the transmission tariff in Norway. In Spain authorized new investments are incorporated in the general tariffs. If the transmission grid is less available than a determined reference level, the grid owner is penalized. This penalty provides for long term signals for new investments in Spain. In California, each grid owner suggests future investments, and is responsible of proposing ways of financing them. Firm Transmission Rights have been introduced as means to promote long-term signals for investments in constraint-reducing investments.

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Chris Marnay is a staff scientist in the Electricity Markets and Policy Group. Chris leads work on modeling of restructured energy markets, especially on problems concerning electricity reliability and renewable power generation. Chris leads the Berkeley Lab's contribution to a multi-institutional research effort on power system reliability in restructured markets called the Consortium for Electric Reliability Technology Solutions (CERTS). The goal of the Berkeley Lab's involvement is to develop power reliability simulation methods and policies for competitive U.S. electricity markets, especially those amenable to supercomputing. Other ongoing work includes maintaining the latest version of the Energy Information Administration's National Energy Modeling System (NEMS) and directing its application to various research topics related to the power sector development and to greenhouse gas emissions abatement. Chris also works on new algorithms for simulating technology choice in competitive electricity markets, and using geographic information systems to simulate renewable electricity generation. Chris began working at LBNL in 1984. He has an A.B. in Development Studies, an M.S. in Agricultural and Resource Economics, and a Ph.D in Energy and Resources, all from the University of California, Berkeley. He has also studied at the London School of Economics and the University of Hawaii, and has worked at the University of Texas at Austin, and in various consulting capacities.